FIRST QUARTER REPORT FISCAL 2011

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BC HYDRO & POWER AUTHORITY MANAGEMENT DISCUSSION AND ANALYSIS

The Management Discussion and Analysis reports on BC Hydro's consolidated results and financial position for the three months ended June 30, 2010 (fiscal 2011). This section should be read in conjunction with the Management Discussion and Analysis presented in the 2010 Annual Report, the 2010 Annual Consolidated Financial Statements of BC Hydro, and the interim consolidated financial statements of BC Hydro for the three months ended June 30, 2010 and 2009. This report contains forward-looking statements, including statements regarding the business and anticipated financial performance of BC Hydro. These statements are subject to a number of risks and uncertainties that may cause actual results to differ from those contemplated in the forward-looking statements.

BC Hydro's results for the first quarter of fiscal 2011 benefited from higher domestic margins than in the same quarter in the prior year, primarily due to increased revenues as a result of higher average domestic customer rates, and from lower finance charges. Energy trading margins were also improved as compared to the prior year and overall trade income improved as moderate strengthening of the U.S. dollar in the current year resulted in small foreign exchange gains on U.S. dollar denominated assets as compared to significant foreign exchange losses experienced in the prior year.

HIGHLIGHTS

- Net income for the three month period ended June 30, 2010 was $91 million, compared to $74 million for the same period in fiscal 2010.

- Hydro generation levels in the quarter were six per cent lower than in the prior year as a result of lower than average water inflows into BC Hydro reservoirs due to low winter snowpack levels and lower than normal precipitation during the spring of 2010. Water inflows into BC Hydro reservoirs during the quarter were at 83 per cent of historic average and are forecast to be at 84 per cent of average through the second quarter due to forecast low precipitation.

- BC Hydro's capital plan for fiscal 2011 is $1.7 billion as the Company continues its programs to address load growth and maintain its aging infrastructure. Property, plant and equipment expenditures for the quarter of $317 million were $46 million lower than during the same period in the prior year primarily due to timing of generation replacement and expansion projects, lower expenditures on distribution projects as a result of the ongoing impact of the economic downturn and lower expenditures on transmission projects.

	For the three months ended June 30		
(in millions)	**2010**	2009	Change
Net Income	**$ 91**	$ 74	$ 17
Number of Domestic Customers	**1,836,117**	1,807,848	28,269
GWh Sold (Domestic)	**11,252**	11,407	(155)
Total Reservoir Storage (GWh)	**20,198**	24,109	(3,911)

(in millions)	***As at June 30 2010***	*(Revised) As at March 31 2010*	*Change*
Total Assets	**$ 18,434**	$ 18,098	$ 336
Retained Earnings	**$ 2,712**	$ 2,621	$ 91
Debt to Equity	**80 : 20**	80 : 20	N/A

CONSOLIDATED RESULTS OF OPERATIONS

As a rate-regulated utility, BC Hydro applies various accounting policies that are acceptable under Canadian generally accepted accounting principles (GAAP) for rate regulated enterprises but differ from enterprises that do not operate in a rate-regulated environment. These policies allow for the deferral of amounts that under GAAP would otherwise be recorded as expenses or income in the current accounting period. The deferred amounts are either recovered or refunded through future rate adjustments.

Commencing in fiscal 2011 BC Hydro changed its reporting of regulatory account transfers on the Statement of Operations to report individual line items after net transfers to regulatory accounts, as compared to prior years in which net transfers to regulatory accounts were reported as a single separate line item and income was reported both before and after regulatory account transfers. Amounts in the prior year's comparative statement of operations have been reclassified to conform to the current year's presentation of changes in regulatory accounts and the current year's classification of operating expenses. Detail on regulatory account transfers can be found in the MD&A and in Note 4 to the Interim Financial Statements.

The transfers to regulatory accounts reflected in net income on the consolidated statement of operations include: variances between forecast amounts from the most recent revenue requirements application and actual results for certain costs, including cost of energy, trade income and finance charges; certain amounts incurred in the current period that are deferred for future recovery in rates (such as demand-side management expenditures and liability provisions); interest accrued on regulatory accounts where allowed; and amortization of regulatory accounts into income.

Net transfers to regulatory accounts of $126 million for the quarter were mainly to the Non-Heritage Deferral Account (NHDA) due to lower than planned domestic revenues before transfers to regulatory accounts and higher purchases for future trade driven by lower market electricity prices, partially offset by lower than planned purchases from Independent Power Producers (IPPs); additions to the Trade Income Deferral Account (TIDA) of the variance between planned and actual trade income; and other net transfers to regulatory accounts for variances relating to interest rates, foreign exchange gains and losses, and expenditures on demand-side management (DSM).

Net income for the first quarter was $91 million, an increase of $17 million from the same period in the prior year mainly as a result of higher domestic revenues due to higher average customer rates and an increase in the rate rider, lower operating costs primarily due to lower expenditures for electricity and gas purchases, lower finance charges, and higher trade income. All variances are after the effect of applicable transfers to regulatory accounts.

REVENUES

For the three months ended June 30	*(in millions)*		*(gigawatt hours)*	
	2010	2009	**2010**	2009
Domestic				
Residential	**$ 281**	$ 281	**3,629**	3,820
Light industrial and commercial	**302**	277	**4,258**	4,273
Large industrial	**125**	108	**3,124**	3,071
Other energy sales	**51**	45	**241**	243
Total Domestic Revenue Before Regulatory Transfer	**759**	711	**11,252**	11,407
Domestic load variance regulatory transfer (to NHDA)	**25**	28	-	-
Total Domestic	**$ 784**	$ 739	**11,252**	11,407
Trade				
Electricity - Gross	**$ 257**	$ 327	**7,062**	9,791
Less: forward electricity purchases[1]	**(122)**	(174)	**-**	-
Electricity - Net	**135**	153	**-**	-
Gas - Gross	**180**	136	**5,167**	4,460
Less: forward gas purchases[1]	**(128)**	(107)	**-**	-
Gas - Net	**52**	29	**-**	-
Total Trade Revenue Before Regulatory Transfer	**187**	182	**12,229**	14,251
Trade regulatory transfer (to TIDA)	**132**	481	**-**	-
Total Trade	**319**	663	**-**	-
Total	**$1,103**	$1,402	**23,481**	25,658

[1] Forward purchases include derivatives which are deducted from gross sales in accordance with generally accepted accounting principles.

Total revenue for the three months ended June 30, 2010 was $1,103 million, a decrease of $299 million compared with the same period last year. Domestic revenues were higher due to higher average rates in all customer classes. Trade revenues were lower as a result of lower average commodity prices and lower electricity sales volumes, partially offset by higher gas trade volumes.

Domestic Revenues

Total domestic revenues of $784 million for the three months ended June 30, 2010 were $45 million or six per cent higher than in the same period in the previous year. The increase was due to higher average customer rates in all rate classes which were increased on an interim basis by 6.11 per cent on April 1, 2010, together with an interim increase in the rate rider from one per cent to four per cent as per BC Hydro's Revenue Requirements Application (RRA) for fiscal 2011. The RRA review process is underway and could conclude in the fall of 2010. Lower residential electricity sales volumes were due to lower usage in that customer class, while light industrial and commercial and large industrial sales volumes were comparable to the same period in the prior year, reflecting economic stabilization in the current year after the severe economic downtown that impacted these customer classes in the prior year. Variances between actual and planned load are deferred to the NHDA.

Trade Revenues

BC Hydro's electricity system is interconnected with systems in Alberta and the western United States. Interconnection facilitates sales and purchases of electricity outside of British Columbia. Energy trade activities are carried out by Powerex, a wholly owned subsidiary of BC Hydro. Trade activities help BC Hydro balance its system by being able to import energy to meet domestic demand when there is a supply shortage in the system due to such factors as low water inflows. Exports are made only after ensuring domestic demand requirements can be met.

Gross trade revenue for the three months ended June 30, 2010 decreased by $26 million from the same period in the prior year due to a decrease in electricity sales, partially offset by an increase in gas sales. The decrease in gross electricity revenue of $70 million was primarily driven by a 28 per cent decrease in electricity sales volumes caused by reduced sales into the Southwest, partially offset by increased sales volumes into Alberta. A 10 per cent increase in average electricity sales prices due to increased natural gas prices, low water conditions in the Northwest, and generation outages in Alberta also offset the lower sales revenues in the Southwest. The decrease in gross electricity sales included a decrease in forward electricity transactions of $52 million which are reported on a net basis in accordance with GAAP. Gross gas revenue increased by $44 million due to a 16 per cent increase in gas sales volumes and an 11 per cent increase in gas sales prices. The increase in gas sales volumes reflects Powerex's strategy to continue to grow its gas business, while the increase in gas prices reflects increased short-term demand due to higher temperatures experienced in eastern North America.

OPERATING COSTS

In fiscal 2011, BC Hydro changed its classification of operating expenses to a presentation of costs based on the nature of the expenditures. Amounts previously reported as operations, maintenance and administration are now classified by the nature of the expense as outlined in Note 8 in the Financial Statements.

For the three months ended June 30, 2010, total operating costs of $908 million were $293 million lower than in the same period in the prior year. The decrease is primarily due to a reduction in the cost of energy as a result of lower electricity and gas market purchases, partially offset by increases in expenditures related to personnel, materials and services and lower capitalized overhead costs.

Cost of energy

Energy costs are influenced primarily by the volume of energy consumed by customers, the mix of sources of supply and market prices of energy. The mix of sources of supply is influenced by variables such as the current and forecast market prices of energy, water inflows, reservoir levels, energy demand and environmental and social impacts.

Energy costs are comprised of the following sources of supply:

For the three months ended June 30	*(in millions)*	
	2010	2009
Domestic		
Water rental payments	**$ 64**	$ 59
Purchases from Independent Power Producers	**148**	113
Other electricity purchases - Domestic	**21**	25
Gas for thermal generation	**10**	10
Transmission charges and other expenses	**21**	12
Allocation to/from trade energy	**25**	25
Total Domestic Cost of Energy Before Regulatory Transfers	**289**	244
Domestic cost of energy regulatory transfers	**(25)**	24
Total Domestic	**$ 264**	$ 268
Trade		
Electricity - Gross	**$ 200**	$ 273
Less: forward electricity purchases[1]	**(122)**	(174)
Electricity - Net	**78**	99
Remarketed gas - Gross	**171**	138
Less: forward gas purchases[1]	**(128)**	(107)
Other gas purchases- Trade - Net	**43**	31
Transmission charges and other expenses	**53**	67
Allocation to/from domestic energy	**(25)**	(25)
Total Trade Cost of Energy Before Regulatory Transfers	**149**	172
Trade cost of energy regulatory transfers	**105**	425
Total Trade	**$ 254**	$ 597
Total Energy Costs	**$ 518**	$ 865

[1] Forward purchases include derivatives which are deducted from gross sales in accordance with generally accepted accounting principles.

Total energy costs for the three months ended June 30, 2010 were $518 million, 40 per cent lower than the same period last year, primarily as a result of lower electricity and gas purchases for trade.

Domestic Energy Costs

Domestic energy costs before regulatory transfers of $289 million were 18 per cent higher than in the same period in the prior year primarily due to higher purchases from IPPs, primarily two new bio-energy projects which started in late fiscal 2010, agreements in the current year to purchase additional energy from two existing IPPs, and increased purchases from Alcan that BC Hydro was required to make due to Alcan's reduced smelter load. Water rental costs increased due to an 8.74 per cent increase on water rental fees and to additional water rental fees associated with the one-third interest in the Waneta dam and generating facility acquired in March 2010. Variances between actual and planned domestic cost of energy are transferred to the Heritage Deferral Account (HDA), NHDA and BCTC Deferral Account (BCTCDA).

Trade Energy Costs

Gross trade energy costs for the three months ended June 30, 2010 decreased by $54 million compared to the same period in fiscal 2010 primarily due to a $73 million decrease in electricity purchases for trade, partially offset by a $33 million increase in remarketed gas purchases. The decrease in electricity purchases for trade included a decrease in forward electricity purchases of $52 million, which are netted in revenue in accordance with GAAP, and a decrease of $21 million in spot electricity purchases. Gross electricity purchases reflect a 32 per cent decrease in electricity purchase volumes mainly in the Northwest which was driven by lower loads in the Southwest. The decreased volumes

were partially offset by an eight per cent increase in average electricity purchase prices driven by increased gas prices and low water conditions in the Northwest. Remarketed gas purchase costs increased by $33 million driven by a 15 per cent increase in gas purchase volumes and an eight per cent increase in the average gas purchase price. As with gas sales, gas purchase volume increases reflect Powerex's strategy to grow its gas business, while the increased average gas purchase price reflects economic improvement over the prior year.

Water Inflows

Water inflows into BC Hydro's reservoirs in the first quarter of fiscal 2011 were seven per cent lower than in the first quarter of last year, and 17 per cent lower than average (average from 1971-2000). For summer of 2010, there is considered to be no risk of spill at either Williston or Kinbasket reservoirs. The BC Hydro Water Supply Forecast (July forecast for February-September 2010 inflows), is estimated at 84 per cent of average, reflecting the impact of low winter snow pack levels and below-normal precipitation during the spring.

The BC Hydro reservoirs have been managed such that the combined storage in BC Hydro reservoirs at June 30, 2010 was 85 per cent of average, compared to 102 per cent of average at June 30, 2009 (average storage levels relate to the average from 1986-2010), with the Williston reservoir on the Peace River system at 79 per cent of average, and the Kinbasket reservoir on the Columbia River system at 90 per cent of average.

Personnel Expenses

Personnel expenses include labour, benefits and employee future benefits. Personnel costs after net regulatory transfers of $131 million for the three months ended June 30, 2010 were $13 million higher than in the same period in the prior year primarily due to higher non-current pension costs.

Materials and External Services

Materials and external services include expenditures for operating and maintenance materials and services provided by third parties. The overall increase in materials and external services expenditures of $12 million as compared to the first quarter of fiscal 2010 is due to increased maintenance and other operational activities.

Amortization and Depreciation

Amortization and depreciation expense includes the depreciation of property, plant and equipment, intangible assets, asset retirement obligation (ARO) assets, amortization of customer contributions and the amortization of certain regulatory assets and liabilities where applicable. For the three months ended June 30, 2010, amortization and depreciation expense was $123 million, compared with $119 million in the same period in the prior year. The increase was primarily due to higher assets in service as a result of BC Hydro's capital expenditure program, after deferring in the regulatory account the variance in actual amortization of capital asset additions as compared to plan, partially offset by lower net regulatory account amortization due to the changes in the composition of the regulatory accounts.

Grants and Taxes

As a Crown Corporation, BC Hydro is exempt from paying federal and provincial income taxes, but pays local government taxes and grants in lieu to municipalities and regional districts. Total grants, school taxes and other local taxes of $45 million reflect an increase of $2 million over the same period in the prior year.

Capitalized Costs

Capitalized costs are capital supporting overhead costs transferred from operating costs to property, plant and equipment. Capitalized costs of $49 million for the three months ended June 30, 2010 are $20 million lower than for the same period in the prior year. The difference is primarily due to a change in the allocation of capitalized overhead costs among quarters during a fiscal year. Prior to fiscal 2011, BC Hydro allocated capitalization of overhead costs among quarters during a fiscal year on a straight-line basis. In fiscal 2011, overhead costs are allocated based on actual levels of capital expenditures during each period. In fiscal 2011, capitalized overhead costs will fluctuate in proportion to the level of capital expenditures in the period, but it is expected to even out by the end of the fiscal year.

Lower capitalized overheads during the three months ended June 30, 2010 also corresponds to lower capital projects expenditures during the period.

FINANCE CHARGES

Finance charges of $104 million for the three months ended June 30, 2010 were $23 million lower than in the same period in the prior year, while finance charges before regulatory account transfers were higher than in the prior year due to foreign exchange translation losses on net unhedged U.S. dollar exposures in the current year due to a weakening of the Canadian dollar against the U.S. dollar as compared with a significant strengthening in the prior year which resulted in translation gains, a higher average volume of debt and higher other finance charges. These variances were partially offset by gains on mark to market adjustments on certain risk management activities and lower capitalized interest. Variances between actual and planned finance charges are transferred to the Foreign Exchange Gains and Losses Regulatory Account and the Finance Charges Regulatory Account.

REGULATORY TRANSFERS

BC Hydro has established various regulatory accounts with the approval of the British Columbia Utilities Commission (BCUC). Regulatory accounts allow BC Hydro to defer certain types of revenue and cost variances through transfers to and from the accounts which have the effect of adjusting net income. The deferred amounts are then included in customer rates in future periods, subject to approval by the BCUC.

The net change in regulatory accounts on the consolidated statement of operations includes: 1) the deferral of differences between planned and actual results for cost of energy (including variances related to load), trade income, finance charges and non-current pension costs; 2) costs deferred for future recovery in rates, such as costs for DSM; and 3) interest accrued on regulatory accounts, where allowed, and amortization of regulatory accounts.

Regulatory transfers are comprised of the following:

	For the three months ended June 30	
(in millions)	**2010**	2009
Variances between forecast and actual costs		
Energy deferral accounts	**$ 81**	$ 43
Finance charges	**(13)**	(39)
Non-current pension deferral	**-**	21
Other	**2**	(7)
	70	18
Deferral of costs for future recovery in rates		
Demand Side Management	**25**	21
Return on Equity	**-**	14
Other	**23**	25
	48	60
Amortization of regulatory accounts	**1**	(18)
Interest on regulatory accounts	**7**	9
Net change in regulatory accounts	**$ 126**	$ 69

For the three months ended June 30, 2010, BC Hydro transferred, on a net basis, $126 million to regulatory accounts, compared with the transfer of $69 million to the regulatory accounts during the same period last year. The majority of the transfers relate to the cost of energy deferral accounts. The net asset balance in the regulatory asset and liability accounts as at June 30, 2010 was an asset of $1,839 million compared to $1,713 million at March 31, 2010.

The significant transfers to the energy deferral accounts reflect lower than planned domestic revenues due to lower consumption, higher energy purchase costs as purchases for future trade were increased to take advantage of low market energy prices, and lower than planned trade income due to low price spreads caused by lower commodity prices for electricity and natural gas. The finance charges deferral reflects a positive variance on short-term interest rates, but to a smaller extent than in the prior year. Non-current pension costs are on plan in the current period as compared to the first quarter of fiscal 2010 when they were significantly higher than planned due to the net actuarial loss experienced by the BC Hydro pension plan in fiscal 2009. The change in amortization of regulatory accounts reflects the changing composition of the balances subject to amortization.

INTERNATIONAL FINANCIAL REPORTING STANDARDS (IFRS)

On February 13, 2008, the Canadian Accounting Standards Board (AcSB) confirmed the adoption of IFRS in place of Canadian GAAP for publicly accountable enterprises. The new requirements are effective for interim and annual reporting periods beginning on or after January 1, 2011. In October 2009, the Canadian Public Sector Accounting Board (PSAB) confirmed the existing guidance whereby Government Business Enterprises (GBEs), which BC Hydro is classified as, adhere to standards for publicly accountable enterprises in the private sector. The Company is currently evaluating the impact of the transition to IFRS on its consolidated financial statements.

Areas with significant differences between IFRS and Canadian GAAP that would impact BC Hydro include: Regulatory Accounting, Property, Plant & Equipment, Provisions and Contingent Liabilities, Employee Benefits, and the overall presentation of financial statements. The initial adoption of IFRS under IFRS 1, *First-time Adoption of International Financial Reporting Standards*, would also result in a number of significant changes.

Accounting for rate-regulated activities is currently under consideration by the International Accounting Standards Board (IASB). The IASB has not developed transitional guidance for use by first-time IFRS adopters with rate-regulated activities that would be adopting IFRS in 2011. Therefore, the AcSB released an exposure draft in July 2010 that proposes that qualifying entities with rate-regulated activities be permitted, but not required, to continue applying the accounting standards in Part V of the CICA Handbook – Accounting for an additional two years rather than adopting IFRS for annual periods beginning on or after January 1, 2011. A final decision by the AcSB is expected no later than December 2010. BC Hydro will be assessing the applicability of the deferral option after the final proposal has been approved.

PAYMENT TO THE PROVINCE

Under a Special Directive from the Province, BC Hydro is required to make an annual payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of BC Hydro's distributable surplus for the most recently completed fiscal year assuming that the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No dividend has been accrued as at June 30, 2010 as it would cause BC Hydro's debt to equity ratio to exceed the 80:20 cap.

LEGAL PROCEEDINGS

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek refunds, damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At June 30, 2010, Powerex was owed US $265 million (CDN $281 million) by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

REGULATION

Revenue Requirement Application

In regulating and setting rates for BC Hydro, the BCUC must ensure that the rates are sufficient to allow BC Hydro to provide reliable electricity service, meet its financial obligations, comply with government policy and achieve a return on equity (ROE). The annual rate of ROE is equal to the pre-income tax annual rate of return allowed by the BCUC to the most comparable investor-owned energy utility regulated under the Utilities Commission Act with a 1.63 per cent adder for the fiscal 2010, 2011 and 2012 years. This is in accordance with Heritage Special Direction No. HC2 as amended by Order in Council No. 074 dated February 17, 2009. The allowed rate of ROE for fiscal 2011 is 14.37 per cent, and is higher than the prior year's allowed rate of 13.05 per cent due to the higher rate of return allowed for Terasen Gas Inc., upon which BC Hydro's rate of return is based.

BC Hydro's F2011 RRA was filed with the BCUC on March 3, 2010 requesting a 6.11 per cent rate increase. The rate increase is attributable to the ongoing implementation of a significant capital program to refurbish BC Hydro's aging assets, an increase in the return on equity, higher costs associated with BC Hydro's pension plan reflecting the impact of market conditions on the valuation of plan assets, and expected lower trade income due to weaker export market conditions. BC Hydro also requested that the rate rider increase by three per cent to partly recover the net balances of the energy deferral accounts. The rate increases were approved by the BCUC on an interim basis effective April 1, 2010. The RRA review process is underway and could conclude in the fall. An Evidentiary Update was filed with the BCUC on July 9, 2010 proposing to defer recovery in fiscal 2011 of higher than previously forecast energy costs.

Large General Service (LGS)

An application to re-design the Large General Service (LGS) rate to provide new conservation rates for BC Hydro's Large General Service customer class was filed with the BCUC on October 16, 2009. A Negotiated Settlement Agreement was reached in April 2010 and was approved by the BCUC on June 29, 2010. The existing LGS rate class will be split into two new customer classes, a new large general service customer class and a new medium general service customer class, with two part rates applied to each customer class (phased-in for medium general service customers). The new rates are to become effective on January 1, 2011. Further rate structures will be designed over the next few years to help BC Hydro meet its energy conservation targets.

Stave Falls Spillway Gates Replacement Project

On December 23, 2009, BC Hydro filed an application with the BCUC for acceptance of an estimated $61.5 million of expenditures associated with the Stave Falls Spillway Gates Replacement Project. The existing gates at the Stave Falls facility were installed in the 1920's and are at end of life. Their replacement will reduce dam safety risks associated with any potential operational failure of the Stave Falls dam during high flood conditions. A written process to review the application was completed at the end of April. The BCUC approved the application on May 13, 2010.

Southern St'at'imc Communities Electrification Project

On December 1, 2009, BC Hydro filed an application with the BCUC for acceptance of the expenditures to provide electric service to the Southern St'at'imc Communities. This was the first application for a First Nation community under BC Hydro's Remote Community Electrification program. A written process to review the application concluded in February. On April 13, 2010, the BCUC determined that the project is in the public interest.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities for the first quarter was $113 million, compared with $35 million for the same period last year. The increase was primarily due to an increase in net income and changes in working capital relative to the prior year, partially offset by regulatory account transfers.

The net long-term debt balance at June 30, 2010 was $11,082 million, compared with $10,705 million at March 31, 2010. The increase was mainly a result of an increase in revolving borrowings of $328 million less $4 million of amortization, an increase of $3 million in debt due to fair value hedge accounting and net foreign exchange revaluation losses of $50 million. The increase in revolving borrowings was due to the funding of capital expenditures and the Payment to the Province.

PROPERTY, PLANT AND EQUIPMENT EXPENDITURES

Property, plant and equipment expenditures were as follows:

	For the three months ended June 30	
(in millions)	**2010**	2009
Distribution improvements and expansion	**$ 88**	$ 102
Generation replacements and expansion	**95**	100
Transmission lines and substation replacements & expansion	**84**	98
General, including computers and vehicles	**50**	63
	$ 317	$ 363

Total property, plant and equipment expenditures presented in this table are different from the amount of property, plant and equipment and intangible asset expenditures in the consolidated Statement of Cash Flows in the interim consolidated financial statements due to effect of accruals related to these expenditures.

Distribution capital expenditures decreased by $14 million in the first quarter of fiscal 2011 compared to the same period in the prior year primarily due to lower levels of work on recurring distribution system projects caused by the economic downturn.

Generation replacements and expansion expenditures decreased by $5 million in the first quarter compared with the same period in the prior year. The decrease was mainly due to lower expenditures on the Revelstoke Unit 5 Installation as this project is nearing completion in fiscal 2011. In addition, in the prior year expenditures were made in the first quarter on various projects that went into service in the third quarter of fiscal 2010, partially offset by increased expenditures on the Mica SF_6 GIS Replacement.

Transmission capital expenditures, planned and completed by British Columbia Transmission Corporation (BCTC) on the assets owned by BC Hydro, decreased by $14 million in the first quarter compared with the same period in the prior year. The decrease was mainly due to the lower expenditures for the Upper Stave & Kwalsa IPP, the Bear Mountain Wind Farm IPP Projects and the Overhead Lines Life Extension, partially offset by increased expenditures on the Selkirk Transformer Addition and the Central Vancouver Island Reinforcement Project.

General capital expenditures decreased by $13 million in the first quarter of fiscal 2011. Expenditures were higher in fiscal 2010 largely due to expenditures on the Home Purchase Offer Program in Tsawwassen.

RISK MANAGEMENT

BC Hydro faces risks to its business that could significantly impact its ability to achieve its short- and long-term financial, social and environmental goals. The goal of risk management is not to eliminate risks, but rather to

mitigate them to levels which are commensurate with potential benefits to be derived. Similarly, BC Hydro's risk management strategies aim to mitigate risks through a consistent risk management process that is applied to day-to-day business activities as well as to specific projects and initiatives. BC Hydro's Chief Risk Officer is responsible for facilitating this risk management process and promoting strong oversight of significant risks by the BC Hydro Risk Management Committee. BC Hydro's Board of Directors also plays a key role in the oversight of risk management, as the Board must understand the risks being taken by BC Hydro and ensure that processes are in place to appropriately manage the risks. BC Hydro's operations involve a broad spectrum of risks ranging from those commonly associated with any business to catastrophic societal loss risks that would have severe effects on entire regions.

The generation and distribution of electricity inherently results in certain safety risks to both BC Hydro workers and the public. To manage worker and public safety, BC Hydro relies on education and training, safe design, safety practice regulations and communication. BC Hydro also prepares emergency response plans to limit injury and loss to life and to restore electric service. The large dams represent a catastrophic loss risk (low probability but high consequence) in terms of life, safety, financial, environmental and reputation. This dam failure risk is managed through a comprehensive dam safety management system involving dam safety professionals and experts.

The most significant risks to the reliability of BC Hydro's system are aging infrastructure and the impact of weather. Reliability risks could also result from either a lack of available generation supply or the associated transmission capacity to meet customer demand. BC Hydro manages these risks through long-term planning, asset maintenance and replacement programs, emergency response programs and reliance on a diverse supply of energy options, and through cooperative support arrangements with neighbouring utilities.

The fiscal 2011 forecast for system inflow energy remains at 86 per cent of normal and the system is forecast to be in a significant net deficit energy position for fiscal 2011. In addition, several factors constrain BC Hydro's ability to use its stored system energy to meet load throughout the year. These factors include generating unit outages at major plants (forced outages and capital projects) as well as water management constraints which limit generation at the major plants during some periods. Even when the system has an annual energy surplus, some electricity purchases may still be required during constrained periods of the year (e.g. fall, winter, early spring), while electricity sales may be needed during other periods to minimize spill from system reservoirs. The value of these purchases and sales is subject to market price risk. Electricity demand is generally increasing as B.C.'s population increases, however this demand can be volatile, particularly from larger customers whose consumption is often driven by export markets and world commodity prices. BC Hydro's risk mitigation strategy is to achieve energy security from domestic sources and through energy conservation and efficiency. BC Hydro regularly models the projected supply-demand balance of the system over the short to medium term, in an effort to meet demand in the most cost effective manner.

Legal and regulatory requirements for First Nation consultation, claims of historic grievances, land claims, and service reliability issues pose risks to BC Hydro. These risks are managed through a comprehensive aboriginal relations program. Building mutually-beneficial relationships with First Nations reduces financial, legal and operating risks.

In meeting its financial performance targets, BC Hydro faces many risks including challenging economic conditions, variable costs and revenues as driven by energy costs, energy demand, interest and foreign exchange rates, pension obligations and energy trading. Of these, risks associated with energy costs – specifically water inflows and energy market prices – are the largest. Tariff rates are set based upon BC Hydro's cost forecast and allowed return on deemed equity. Many financial risks (differences between forecast and actual costs) associated with uncontrollable costs are mitigated through regulatory deferral accounts. Increasing costs due to aging infrastructure, the modernization and refurbishment of the electricity system, the need for new supply and the need to manage environmental impacts create challenges for BC Hydro in maintaining a cost advantage.

BC Hydro's energy trading subsidiary, Powerex, is exposed to the risk of variable market prices and counterparties who might not meet their obligations. Powerex manages these risks by operating through defined limits that are regularly reviewed by both the Powerex and BC Hydro Boards of Directors.

The economic contraction has continued to improve the labour supply of engineers and senior managers and has also improved BC Hydro's ability to attract and retain staff in a variety of roles. The economic downturn has also had the effect of delaying employee retirements; however this may result in a sudden surge of retirements in the future with shorter notice periods. Apprentice and job-sharing programs partially mitigate this risk. In addition, the return on pension fund assets and the market discount rate at year end can have a significant impact on the cost of providing employee future benefits.

Areas where BC Hydro is exposed to the risk of non-compliance with environmental regulations include the release of hazardous materials into the environment and endangerment of wildlife and their habitats. These risks are managed through environmental management systems and risk mitigation strategies.

Other risks to BC Hydro have not changed materially from the Management Discussion and Analysis in the 2010 Annual Report.

FUTURE OUTLOOK

The *Budget Transparency and Accountability Act* requires that BC Hydro file a Service Plan each year. BC Hydro's Service Plan filed in March 2010 forecast income before regulatory account transfers for fiscal 2011 at $257 million and net income forecast at $609 million.

BC Hydro's earnings can fluctuate significantly due to various non-controllable factors such as the level of water inflows, customer load, market prices for electricity and natural gas, weather temperatures, interest rates and foreign exchange rates. The impact to net income of these non-controllable factors is largely mitigated through the use of regulatory accounts. The Service Plan forecast assumes average water inflows for fiscal 2011, customer load of 51,550 GWh, average market energy prices of CDN $36.80/MWh, short-term interest rates of 1.02 per cent and a US dollar exchange rate of US $0.9611, an allowed return on equity of 14.37 per cent, and an interim rate increase of 6.11 per cent for fiscal 2011.

BC Hydro filed an updated forecast with the BCUC as part of BC Hydro's Evidentiary Update to its Revenue Requirement Application on July 9, 2010. The significant changes from the Service Plan for fiscal 2011 include:

- An increase in the forecast cost of energy primarily due to the impact of lower forecast water inflows. Total system inflow based on April snowpack levels for fiscal 2011 was expected to be 90 per cent of average at the time the forecast was prepared. As a result, hydro-generation is forecast to decrease by approximately 6,000 GWh from the Service Plan and be replaced by market energy purchases. Since that time the forecast system inflow has been updated and the July forecast is 84 per cent of average. This will be reflected in next quarter's forecast.

- An increase in customer load of 244 GWh for total customer load of 51,794 GWh. This increase is largely due to changes in expected DSM savings, an update to the forecast of industrial sales, and the impact of price elasticity.

- A decrease in short term interest rates to 0.81 per cent and a U.S. dollar exchange rate of US $0.982.

BC Hydro, as part of its Evidentiary Update, has proposed to maintain the fiscal 2011 interim rate increase at 6.11 per cent and that the changes from the Service Plan, mainly as a result of the impact of low water inflows flow through the NHDA. The total proposed transfer to the NHDA is $223 million and would be collected in future years through the rate rider. However, if all the changes were reflected in BC Hydro's applied-for rate increase instead of the proposed transfer to the NHDA, the requested annual rate increase would increase to 13.57 per cent from the proposed 6.11 per cent. As a result of these changes, net income is forecast at $605 million. Any requested rate increase requires the approval of the BCUC. The RRA review process is underway and could conclude in the fall of 2010.

FINANCIAL STATEMENTS

CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(in millions)	*For the three months ended June 30* 2010	2009 *(Revised Note 1)*
Revenues		
Domestic	**$ 784**	$ 739
Trade	**319**	663
	1,103	1,402
Expenses		
Operating Costs		
Cost of energy (Note 8)	**518**	865
Other operating expenses (Note 8)	**390**	336
	908	1,201
Finance Charges	**104**	127
	1,012	1,328
Net Income	**$ 91**	$ 74

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(Unaudited)

(in millions)	*For the three months ended June 30* 2010	2009
Net Income	**$ 91**	$ 74
Other Comprehensive Income (Loss) (Note 7)	**(18)**	38
Comprehensive Income	**$ 73**	$ 112

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(Unaudited)

(in millions)	*For the three months ended June 30* 2010	2009
Retained Earnings, Beginning of Period	**$ 2,621**	$ 2,221
Net Income	**91**	74
Retained Earnings, End of Period	**$ 2,712**	$ 2,295

See accompanying notes to the interim consolidated financial statements.

CONSOLIDATED BALANCE SHEET

(Unaudited) *(in millions)*	***As at June 30 2010***	*(Revised Note 1)* *As at March 31 2010*
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 46**	$ 9
Accounts receivable and accrued revenue	**579**	650
Inventories (Note 2)	**163**	118
Prepaid expenses	**92**	131
Current portion of derivative financial instrument assets	**348**	434
	1,228	1,342
Other Assets		
Property, plant and equipment	**14,191**	13,822
Intangible assets	**272**	282
Regulatory assets (Note 4)	**2,240**	2,157
Sinking funds	**102**	96
Employee future benefits	**309**	313
Derivative financial instrument assets	**92**	86
	17,206	16,756
	$ 18,434	$ 18,098
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 979**	$ 1,101
Current portion of long-term debt	**2,402**	2,074
Current portion of derivative financial instrument liabilities	**285**	393
	3,666	3,568
Other Liabilities		
Long-term debt	**8,782**	8,727
Regulatory liabilities (Note 4)	**401**	444
Deferred contributions	**1,086**	1,079
Derivative financial instrument liabilities, long-term	**192**	224
Other long-term liabilities	**1,560**	1,382
	12,021	11,856
Shareholder's Equity		
Retained earnings	**2,712**	2,621
Accumulated other comprehensive income (Note 7)	**35**	53
	2,747	2,674
	$ 18,434	$ 18,098

Commitments and Contingencies (Note 9)

Subsequent Event (Note 10)

See accompanying notes to the interim consolidated financial statements.

Approved on behalf of the Board:

Dan Doyle
Chairman

Tracey L. McVicar
Chair, Audit and Risk Management Committee

CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)	*For the three months ended June 30*	
(in millions)	**2010**	2009
Operating Activities		
Net income	**$ 91**	$ 74
Regulatory account transfers	**(120)**	(83)
Adjustments for non-cash items:		
Amortization of regulatory accounts (Note 4)	**(1)**	18
Amortization expense	**109**	99
Foreign exchange translation (gains) losses	**6**	(13)
Unrealized (gains) losses on mark-to-market	**(30)**	(6)
Other items	**21**	1
	76	90
Changes in non-cash working capital:		
Accounts receivable and accrued revenue	**71**	16
Accounts payable and accrued interest	**(28)**	(128)
Prepaid expenses	**39**	84
Inventories	**(45)**	(27)
	37	(55)
Cash provided by operating activities	**113**	35
Investing Activities		
Property, plant and equipment and intangible asset expenditures	**(367)**	(357)
Deferred contributions	**12**	13
Other items	**(1)**	(2)
Cash used in investing activities	**(356)**	(346)
Financing Activities		
Bonds		
Issued	**-**	477
Retired	**-**	(432)
Revolving borrowings	**327**	211
Sinking fund withdrawals	**-**	2
Debt issue and related costs	**-**	(5)
Payment to the Province	**(47)**	-
Settlement of derivative instruments	**-**	8
Cash provided by financing activities	**280**	261
Increase in cash and cash equivalents	**37**	(50)
Cash and cash equivalents, beginning of period	**9**	190
Cash and cash equivalents, end of period	**$ 46**	$ 140
Supplemental Disclosure of Cash Flow Information		
Interest paid	**$ 168**	$ 144
Non-cash transaction:		
Capital lease obligation included in other liabilities	**$ 171**	$ -

See accompanying notes to the interim consolidated financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED) JUNE 30, 2010

DESCRIPTION

British Columbia Hydro and Power Authority (BC Hydro or the Company) was established in 1962 as a Crown Corporation of the Province of British Columbia (the Province) by enactment of the *Hydro and Power Authority Act*. As directed by the *Hydro and Power Authority Act*, BC Hydro's mandate is to generate, manufacture, distribute and supply power. BC Hydro's corporate purpose is to provide "Reliable power, at low cost, for generations." BC Hydro is subject to regulation (see Note 4) by the British Columbia Utilities Commission (BCUC) which, among other things, approves the rates BC Hydro charges for its services.

BC Hydro owns and operates electric generation and distribution facilities in the Province. BC Hydro also owns transmission facilities in the Province that are operated by British Columbia Transmission Corporation (BCTC), an independent Crown Corporation of the Province up to July 5, 2010. As of July 5, 2010, BCTC and BC Hydro integrated as a single organization as per the *Clean Energy Act* (Note 10).

NOTE 1: ACCOUNTING POLICIES

Basis of Presentation

The interim consolidated financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles (GAAP) for preparation of interim financial statements and do not conform in all respects to the disclosure requirements for annual financial statements. BC Hydro follows certain accounting practices that reflect the effects of regulation, and differ from the accounting practices for enterprises that do not operate in a rate-regulated environment. These interim consolidated financial statements and the notes should be read in conjunction with the Annual Consolidated Financial Statements and accompanying notes in BC Hydro's 2010 Annual Report.

These interim consolidated financial statements follow the same accounting policies as those described in BC Hydro's 2010 Annual Report.

Certain amounts in the prior year's statements related to inventories, prepaid expenses, and regulatory assets and regulatory liabilities have been reclassified to conform to the current year's presentation. Certain amounts in the prior year's statement of operations have been reclassified to conform to a change in the current year's classification of operating expenses to a presentation of costs based on the nature of the expenditures. Amounts previously presented as operations, maintenance and administration costs are now classified by the nature of the expense as outlined in Note 8.

In addition, the Company has changed its presentation of the impact of regulation on its statement of operations. In prior periods the impact of regulatory accounting was shown as a single line item whereas in the current period the impact of regulation is netted against the corresponding expense or revenue line item in the statement of operations. This change results in the Company's presentation being more consistent with other regulated utilities in Canada. Comparative balances have been reclassified to conform with the current period's presentation. Detail on regulatory account transfers can be found in Note 4.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets, liabilities and commitments at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Significant items subject to management estimates and assumptions include the determination of the allowance for doubtful accounts, the fair value of sinking funds and derivative financial instruments, the actuarial assumptions used to value the employee future benefit plans, the useful lives of property, plant and equipment and intangible assets, amounts for accrued liabilities and contingencies, and the accrual for unbilled revenue at period end. Actual results could differ from these estimates.

NOTE 2: INVENTORIES

(in millions)	As at June 30 2010	As at March 31 2010
Materials and supplies	$ 78	$ 77
Natural gas trading inventories	85	41
	$ 163	$ 118

NOTE 3: SEASONALITY OF OPERATING RESULTS

Due to the seasonal nature of BC Hydro's operations, the interim consolidated statement of operations is not indicative of operations on an annual basis. Seasonal impacts of weather, including its impact on water inflows, energy consumption within the region and market prices of energy, can have a significant impact on BC Hydro's operating results.

NOTE 4: REGULATION

BC Hydro is regulated by the BCUC, and both entities are subject to general or special directives and directions issued by the Province. BC Hydro operates primarily under a cost of service regulation as prescribed by the BCUC. Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual payment to the Province. Calculation of its revenue requirements and rates charged to customers are established through applications filed with and approved by the BCUC.

BC Hydro applies various accounting policies that differ from GAAP for enterprises that do not operate in a rate-regulated environment. Generally, these policies result in deferral and amortization of costs and recoveries to allow for adjustment of future rates. In the absence of rate-regulation, these amounts would otherwise be included in the determination of net income in the period the amounts are incurred. These accounting policies support BC Hydro's regulation and have been established through ongoing application to and approval by the BCUC. To the extent that a regulatory account has been, or will be applied for, and in management's estimate, acceptance of deferral treatment by the BCUC is considered probable, the Company will defer such costs in advance of a final decision of the BCUC. Should the BCUC deny the application for regulatory treatment, the amount deferred would be recorded in net income at such time.

BC Hydro's F2011 Revenue Requirement Application (RRA) was filed with the BCUC on March 3, 2010 requesting a 6.11 per cent rate increase. The rate increase is attributable to the ongoing implementation of a significant capital program to refurbish BC Hydro's aging assets, an increase in the return on equity, higher costs associated with BC Hydro's pension plan reflecting the impact of market conditions on the valuation of plan assets, and expected lower trade income due to weaker export market conditions. BC Hydro also requested that the rate rider increase by three per cent to partly recover the net balances of the energy deferral accounts. The rate increases were approved by the BCUC on an interim basis effective April 1, 2010. An Evidentiary Update was filed with the BCUC on July 9, 2010. The RRA review process is underway and could conclude in the fall.

Regulatory Accounts

The following regulatory assets and liabilities have been established through rate regulation. For the three months ended June 30, 2010, the impact of regulatory accounting has resulted in an increase to net income of $126 million (2009 – $69 million increase respectively).

(in millions)	*(Revised) April 1 2010*	*Addition (Reduction)*	*Amortization*	*Net change*	*June 30 2010*
Regulatory Assets					
Heritage Deferral Account	$ 325	$ 6	$ (16)	$ (10)	$ 315
Non-Heritage Deferral Account	119	47	(6)	41	160
BCTC Deferral Account	18	7	(1)	6	24
Trade Income Deferral Account - Asset	122	29	(6)	23	145
Demand-Side Management Programs	442	25	(16)	9	451
First Nation Negotiations, Litigation and Settlement Costs	399	2	(2)	-	399
Non-Current Pension Cost	86	-	(4)	(4)	82
Site C	60	6	-	6	66
Environmental Compliance	321	3	(1)	2	323
Other Regulatory Accounts	265	11	(1)	10	275
Total Regulatory Assets	2,157	136	(53)	83	2,240
Regulatory Liabilities					
Future Removal and Site Restoration Costs	159	-	(4)	(4)	155
Foreign Exchange Gains and Losses	101	(6)	-	(6)	95
Finance Charges	104	12	(37)	(25)	79
Other Regulatory Accounts	80	5	(13)	(8)	72
Total Regulatory Liabilities	444	11	(54)	(43)	401
Net Regulatory Asset	$1,713	$ 125	$ 1	$ 126	$1,839

Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province.

On May 28, 2010, the BCUC approved BC Hydro's application to establish the Environmental Compliance regulatory account pertaining to compliance with Federal Polychlorinated Biphenyl (PCB) Regulations and the remediation of environmental contamination at one of the Company's properties.

Other regulatory asset accounts with individual balances less than $65 million include the following: Depreciation Study Adjustments, Contributions in Aid of Construction Amortization Variance, Capital Project Investigation Costs, Smart Metering and Infrastructure Project Costs (SMI), GM Shrum Unit 3 Outage, Home Purchase Option Program, Return on Equity (ROE) Adjustment and Waneta. BC Hydro has applied for the Waneta Regulatory Account which is intended to smooth out the rate impact of the acquisition of a one-third interest in the Waneta dam and generating facility from Teck Metals Ltd. The total Waneta deferral account as at June 30, 2010 is $8 million.

BC Hydro has applied for and awaiting approval for deferral of fiscal 2011 costs for SMI, which are $2 million (asset) as at June 30, 2010.

Other regulatory liability accounts with individual balances less than $65 million include the following: Net Employment Costs, Amortization of Capital Additions, Taxes, and Storm Damage.

NOTE 5: CAPITAL MANAGEMENT

Orders in Council from the Province establish the basis for determining BC Hydro's equity for regulatory purposes, as well as its allowed return on equity and the annual Payment to the Province. Capital requirements are consequently managed through the retention of equity subsequent to the Payment to the Province and the imposed requirement of maintaining a debt to equity ratio not exceeding 80:20.

BC Hydro monitors its capital structure on the basis of its debt to equity ratio. For this purpose, BC Hydro defines debt as long-term debt less investments held in sinking funds and temporary investments. Equity as defined for regulatory purposes comprises retained earnings and accumulated other comprehensive income.

BC Hydro manages its capital so as not to exceed the 80:20 debt to equity ratio as defined by the Province. During the period, there were no changes in this approach to capital management.

The debt to equity ratio, based on equity as defined for regulatory purposes, at June 30, 2010 and March 31, 2010 was as follows:

(in millions)	***As at June 30 2010***	*As at March 31 2010*
Total long-term debt, net of sinking funds	**$ 11,082**	$ 10,705
Less: cash and cash equivalents	**(46)**	(9)
Net Debt	**$ 11,036**	$ 10,696
Retained earnings	**$ 2,712**	$ 2,621
Accumulated other comprehensive income	**35**	53
Total Equity	**$ 2,747**	$ 2,674
Net Debt to Equity Ratio for Regulatory Purposes	**80 : 20**	80 : 20

Under a Special Directive from the Province, BC Hydro is required to make an annual Payment to the Province (the Payment) on or before June 30 of each year. The Payment is equal to 85 per cent of BC Hydro's distributable surplus for the most recently completed fiscal year assuming that the debt to equity ratio, as defined by the Province, after deducting the Payment, is not greater than 80:20. If the Payment would result in a debt to equity ratio exceeding 80:20, then the Payment will be based on the greatest amount that can be paid without causing the debt to equity ratio to exceed 80:20. No dividend has been accrued as at June 30, 2010, as it would cause BC Hydro's debt to equity ratio to be over the 80:20 cap.

NOTE 6: EMPLOYEE FUTURE BENEFITS

BC Hydro's cost for employee future benefits for the three months ended June 30, 2010 was $26 million (2009 – $24 million).

NOTE 7 OTHER COMPREHENSIVE INCOME (LOSS) & ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Other Comprehensive Income (Loss)

(in millions)	*For the three months ended June 30* **2010**	2009
Other Comprehensive Income (Loss)		
Unrealized gain (loss) on derivatives designated as cash flow hedges	**$ 26**	$ (62)
Reclassification to income of (loss) gain on derivatives designated as cash flow hedges	**(44)**	100
Other Comprehensive (Loss) Income	**$ (18)**	$ 38

Accumulated Other Comprehensive Income (Loss)

(in millions)	*For the three months ended June 30* **2010**	2009
Accumulated other comprehensive income (loss), beginning of period	**$ 53**	$ (42)
Other comprehensive income (loss) for the period	**(18)**	38
Accumulated Other Comprehensive Income (Loss), End of Period	**$ 35**	$ (4)

NOTE 8 OPERATING COSTS

(in millions)	*For the three months ended June 30* **2010**	2009
Electricity and gas purchases	**$ 372**	$ 723
Water rentals	**71**	67
Transmission charges	**75**	75
Cost of Energy	**$ 518**	$ 865

(in millions)	*For the three months ended June 30* **2010**	2009
Personnel expenses	**$ 131**	$ 118
Materials and external services	**144**	132
Amortization and depreciation	**123**	119
Grants and taxes	**45**	43
Capitalized costs	**(49)**	(69)
Other costs	**(4)**	(7)
Other Operating Costs	**$ 390**	$ 336

Amortization and depreciation is shown net of amortization of $14 million of regulatory accounts (2009 - $20 million).

NOTE 9: COMMITMENTS AND CONTINGENCIES

Legal Proceedings

Since 2000, Powerex has been named, along with other energy providers, in lawsuits and U.S. federal regulatory proceedings which seek refunds, damages and/or contract rescissions based on allegations that, during part of 2000 and 2001, the California wholesale electricity markets were unlawfully manipulated and energy prices were not just and reasonable. At June 30, 2010, Powerex was owed US $265 million (CDN $281 million) by the California Power Exchange and the California Independent System Operator related to Powerex's trade activities in California during the period covered by the lawsuits. It is expected those receivables will be offset against any refunds that Powerex is required to pay.

Due to the ongoing nature of the regulatory and legal proceedings against Powerex, management cannot predict the outcomes of the claims against Powerex. Powerex has recorded provisions for uncollectible amounts and legal costs associated with the California energy crisis. These provisions are based on management's best estimates, and are intended to adequately provide for any exposure. However, the amounts that are ultimately collected or paid may differ from management's current estimates. Management has not disclosed the provision amounts or ranges of expected outcomes due to the potentially adverse effect on the process.

NOTE 10: SUBSEQUENT EVENT

Consolidation of BC Transmission Corporation

On June 3, 2010, the Province enacted the *Clean Energy Act* (the Act) in the B.C. Legislature. The Act sets the foundation for a new future of electricity self-sufficiency powered by unprecedented investments in clean, renewable energy across the province. The Act will consolidate BC Hydro and BCTC into a single organization with one board of directors and executive, and the transfer of all BCTC assets, liabilities and employees to BC Hydro, effective July 5, 2010.